of new retrofit scrubbers to meet these predetermined requirements. Since utilities must reduce emissions to levels well below current SIP standards under the options considered here, the ability to use scrubbers to achieve stricter limits must be present. Upper limits on retrofit capacity, however, are also imposed, based on figures provided by the EIA. 4/ These enhancements increased the size of the model to nearly 3,400 rows, over 15,000 columns, and about 115,000 nonzero coefficients.

All policy effects (mandated reductions, subsidies, or taxes) are captured in the 1995 solution, the compliance date stipulated in many bills introduced into the 98th Congress. Additional programs were constructed to convert the 1995 results from the NCM5 into streams of cost, revenues, and subsidy levels during the period from 1986 through 2015. These are described later in the appendix.

Finally, the National Utility Financial Statement (NUFS) was coupled to the NCM5 in order to produce the electricity rate estimates for all options. This model is also housed and maintained at the EIA. Inputs into NUFS include the annualized capital, fuel, and nonfuel O&M costs, as well as regional generation, consumption, imports, and exports of electricity. The NUFS model transforms this information (from all three solution years) into a simple financial statement for each region's utilities, and derives a 10-year profile of electricity rates from the revenue requirements. The CBO also revised some of the financial assumptions embodied in NUFS so that they would conform with CBO assumptions.

Polluter Pays Options in Chapter II. No additional modifications were necessary to simulate the 8 million ton and 10 million ton rollback schemes found in Chapter II, since the NCM5 had been previously modified by the EIA to study these types of policies. The regional emission targets were applied to non-NSPS coal- and oil-fired sources, based on the excess emission formula and using 1980 emissions as a baseline. Table A-3 shows the limits imposed on each state. The 1980 emissions are higher than the 1985 model predictions because of the assumption that all plants are currently in compliance with local SIP standards. Progress toward SIP compliance did in fact occur during this period, and, when this is combined with fairly flat demand growth (averaging only 1.7 percent per year), 1985 estimates seem quite plausible. 5/

4. These figures were based on the "Acid Rain Boiler Population Retrofit Analysis" performed by PEDCo Environmental, Inc., for the Department of Energy in April 1983.

5. The OTA study from which CBO takes emission levels estimates that in 1980 utilities emitted roughly 1.4 million tons more than allowed under the SIP standards. Office of Technology Assessment, *An Analysis of the Sikorsky/Waxman Acid Rain Control Proposal: H.R.3400, "The National Acid Deposition Control Act of 1983,"* Staff Memorandum, revised July 12, 1983.

The regional emission targets are incorporated into the NCM5 by imposing a constraint (less than or equal to) on the sum of utility SO_2 emissions within a state. When the NCM5 divides states into more than two or three regions, the constraint applies only to the statewide total. When two or more states comprise an NCM5 region, the individual state targets were summed to construct the constraint. A very limited regional trading scheme was allowed, since states were allowed to exceed their emission targets by 5 percent, as long as the overall national constraint was satisfied.

TABLE A-3. SO_2 REDUCTIONS REQUIRED BY THE EXCESS EMISSIONS FORMULA, BY STATE (In thousands of tons of SO_2)

State	1980 Emissions	8 Million Ton Reduction		10 Million Ton Reduction	
		Amount	Percent	Amount	Percent
Alabama	543	225	41	281	52
Arizona	88	0	0	0	0
Arkansas	27	1	2	1	2
California	78	0	0	0	0
Colorado	78	0	0	0	0
Connecticut	32	0	0	0	0
Delaware	53	13	25	17	32
District of Columbia	5	0	0	0	0
Florida	726	267	37	334	46
Georgia	737	363	49	454	62
Idaho	0	0	0	0	0
Illinois	1,126	603	54	753	67
Indiana	1,540	938	61	1,172	76
Iowa	231	101	43	126	54
Kansas	150	60	40	75	50
Kentucky	1,008	567	56	708	70
Louisiana	25	0	0	0	0
Maine	16	2	13	3	17
Maryland	223	86	39	108	48
Massachusetts	276	83	30	104	38
Michigan	565	187	33	233	41
Minnesota	177	51	29	63	36
Missippi	129	57	45	72	56
Missouri	1,141	716	63	895	78
Montana	23	1	5	2	6
Nebraska	50	6	12	8	15

(Continued)

The "RETAIN" feature was used to simulate a policy of restricted fuel switching. RETAIN is an NCM5 function that specifies a lower limit on specific coal shipments based on the previous solution; setting RETAIN equal to 9 would ensure that at least 90 percent of a coal shipment of a certain sulfur content could be maintained in the subsequent solution (five years later). Thus, a value of 9 would preserve about 80 percent of current coal patterns between 1985 and 1995. In the base case, RETAIN equalled 5, and under all other acid rain policies, RETAIN was set at 1. This latter

TABLE A-3. (Continued)

State	1980 Emissions	8 Million Ton Reduction		10 Million Ton Reduction	
		Amount	Percent	Amount	Percent
Nevada	40	0	0	0	0
New Hampshire	81	40	49	49	61
New Jersey	110	30	27	37	34
New Mexico	85	0	0	0	0
New York	480	178	37	222	46
North Carolina	435	69	16	87	20
North Dakota	83	9	11	12	14
Ohio	2,172	1,272	59	1,590	73
Oklahoma	38	0	0	0	0
Oregon	3	0	0	0	0
Pennsylvania	1,466	677	46	846	58
Rhode Island	5	0	0	0	0
South Carolina	213	75	35	94	44
South Dakota	29	7	25	9	31
Tennessee	934	533	57	666	71
Texas	303	9	3	12	4
Utah	22	0	0	0	0
Vermont	1	0	0	0	0
Virginia	164	21	13	26	16
Washington	69	17	25	22	31
West Virginia	944	457	48	571	61
Wisconsin	486	274	56	343	71
Wyoming	121	6	5	7	6
Total	17,325	8,000	46	10,000	58

SOURCE: Congressional Budget Office, from Office of Technology Assessment, *An Analysis of the Sikorsky/Waxman Acid Rain Control Proposal: H.R.3400, "The National Acid Deposition Control Act of 1983,"* Staff Memorandum, revised July 12, 1983.

value reflects the assumption that utilities could break nearly all long-term coal contracts over a 10-year period if the Congress enacted major legislation to reduce SO_2 emissions.

Subsidized Scrubber Options with Generation Taxes in Chapter III. Both the 8 million ton and 10 million ton rollbacks were examined, using the identical emission constraints imposed in Chapter II. Each level of control was accompanied by (1) a 90 percent capital subsidy for retrofit scrubbers, and (2) a 90 percent capital subsidy combined with a 50 percent O&M subsidy for operating the scrubbers. For the capital subsidy, the coefficients in the 1995 objective function that represent the building of a retrofit scrubber were simply reduced by 90 percent. For the O&M subsidy, the 1995 coefficients that represent the operation (generation) of a retrofitted plant were reduced by an amount equal to 50 percent of the variable costs attributed to scrubber operation.

The "Top 50" approach, as embodied in H.R. 3400 (Option III-2C), required more complicated modifications. The list of the top 50 emitters was taken directly from a study done by the Office of Technology Assesment. 6/ In 1995 the appropriate SIP capacity was deducted from the regions affected, most of which was rebuilt at the cost of constructing retrofit scrubbers conforming to the revised NSPS, subsidized at 90 percent. A few plants were simply retired, based on the PEDCo analysis which found them to be impossible or highly uneconomic to retrofit. 7/ This proceedure retained the correct heat rates for the plants and recorded the appropriate capital costs. An additional 90 percent capital subsidy was included for other retrofit scrubbers required to meet the remaining emission targets.

Emission Tax and Subsidy Options in Chapter IV. A tax of $600 per ton of SO_2 emitted ($.30/lb.) was added to the 1995 objective function coefficients that represent the operation of pre-NSPS coal- and oil-fired capacity. The tax was based on calculated emission rates that differ by plant type, fuel, load, and scrubber removal efficiency. Revenues were calculated based on the observed emission levels. In addition, two subsidy levels were granted, as in Chapter III.

Sulfur Content Taxes and Subsidies in Chapter V. In 1995 the coefficients that represent coal supply curves were increased by the appropriate (per

6. See Office of Technology Assessment, *An Analysis of the Sikorsky/Waxman Acid Rain Proposal.*

7. These plants are listed in Office of Technology Assessment, *Additional Analyses of H.R. 3400: "The National Acid Deposition Control Act of 1983,"* Staff Memorandum, September 16, 1983.

ton) tax rates, and equilibrium tax revenues were computed in the coal report program by multiplying the volume of shipments by the specific tax rate applied. A 90 percent capital subsidy was granted for retrofit scrubber installation as well as the \$0.50 per pound subsidy granted for each pound of sulfur removed by all scrubbers, including NSPS plants. The latter subsidy was granted by reducing the coefficients of the 1995 objective function that accounted for scrubber operation, based on the calculated removal efficiency and sulfur content of the coal burned.

Recent Proposals in Chapter VI. Since Option VI-1 was based on specific state emission targets, no modifications were required. The emission targets that applied to pre-NSPS sources were obtained from the Office of Technology Assessment, based on an annual average statewide SO_2 emission rate of 1.2 pounds per million Btus. These were incorporated as strict targets, and did not allow individual states the opportunity to exceed their limits by five percent, as permitted in Chapters II and III.

Options VI-2 and VI-3 did not use regional emission targets, but instead were based on all plants meeting specified SO_2 emission rates--1.2 pounds per million Btus for Option VI-2, and 0.7 pounds per million Btus under Option VI-3. First, additional columns were created to represent the operation of retrofit scrubbers at these standards (although for Option VI-3 the scrubbing standard was actually 0.67 pounds per million Btus, since it currently existed in the model). Then, preexisting columns were identified that represented the operation of an unscrubbed plant while burning a coal with sulfur content in excess of the standard, as well as those that portrayed the operation of a scrubbed plant under a more lenient standard than specified in the bills. To stimulate these two policies, the cost of these latter activities were increased to prohibitive levels in the 1995 solution. The solution therefore only allowed the use of plants that complied with the uniform emission rate standard. (Under Option VI-3, coal emitting up to 0.8 pounds of SO_2 per million Btus could be burned without a scrubber, because it is the cleanest category of coal specified in the model.)

ADDITIONAL MODELS

The CBO constructed several smaller models to transform the NCM5 output into the values reported in the tables and text of this paper. The least complex of these simply aggregates the NCM5 results into larger regions, such as states. Another model sums the levelized capital expenditures for the three solution years, and adds the variable cost of the 1995 solution to this in order to approximate the annual costs incurred by utilities in 1995 under different options. The final simple model converts tons of coal mined in each region into labor requirements ("miner years") by applying an appropriate multiplier for each region based on 1983 average productivity.

Two other models warrant a more detailed explanation: the trust fund model and the discounted program cost model.

The Trust Fund Model. The model that computes trust fund balances differs slightly from chapter to chapter, depending on the assumed timing of receipts and outlays. In all cases, however, the model computes real end-of-year balances, based on a real interest rate of 3.7 percent. This represents the CBO forecast of real interest on new debt issued by the Treasury (weighted by maturities). Administrative expenses of $25 million per year are included as outlays each year.

The generation taxes (Chapter III) are not incorporated into the NCM5, but are based instead on predicted fossil fuel generation. Therefore, these taxes neither affect overall electricity consumption nor the dispatching decisions of electric utilities. Such an assumption is warranted by the level and duration of the tax, and the limited opportunities for substitution of hydroelectric and nuclear generation. The tax levels were chosen in order to generate sufficient revenues over 10 years to cover all subsidy obligations predicted by the NCM5.

The annual outlays in Chapter III are based on the response of utilities to the available subsidies. The trust fund outlays for the capital subsidy rise gradually from 1991 until they reach the "steady state" annual level required in 1995. These are then tapered off steadily in the 2011-2015 period. The O&M subsidy begins in 1995 at the annual level suggested by the NCM5 solution, and remains constant through 2015, after which all subsidies expire. The 1995 commencement assumption reflects the lack of incentive for utilities to finish and operate scrubbers until the compliance date.

The tax revenues in Chapter IV and Chapter V are determined by the 1995 solution of the NCM5. In both cases, 1986 revenues are calculated on the 1985 tax base observed in the absence of the tax. This provides a static revenue estimate based on the assumption that utilities can not alter their decisions in a short time in order to reduce tax liabilities. The stream of revenues and outlays between 1986 and 1995, however, requires more assumptions about how quickly the utilities achieve the "steady state" solution predicted by the NCM5.

The direct emission tax policies examined in Chapter IV generate so much more revenue than subsidy obligations that trust fund balances are less of a concern. An account of government holdings is kept, however, for the net present value calculation, and assumes a simple linear decline in emission tax revenues between 1986 and 1995, with both the capital and O&M subsidies rising steadily between 1991 and 1995. The revenue levels remain constant until 2010, after which they decline because of the retirement of two-thirds of the taxed sources by 2015. Similarly, the subsidies gradually decline to zero by the end of 2015.

In the Chapter V policies that tax the sulfur content of coal to provide subsidies for scrubbing, the revenues also decline steadily between 1986 and 1995. On the outlay side, the capital subsidy is phased in between 1991 and 1995. The subsidy for emission reduction, however, takes current scrubbing into account; the 1986 subsidy is based simply on the amount of sulfur removed by scrubbers in 1985. This amount rises slightly as planned scrubbers are constructed for the 1990 solution (without tax incentives taken into account), and steadily increases between 1991 and 1995 to reach the levels predicted by the model. All taxes and outlays remain constant until 2015.

The Discounted Program Cost Model. The inputs into this model include the change in annual utility costs (both capital and variable, as measured against the base case), as well as the level of subsidies, taxes, trust fund balances, and emission reductions. These results are combined with assumptions concerning the timing of expenditures and emission reductions--conforming to the assumptions employed in the trust fund model--to construct a yearly stream of resource costs attributed to the option from 1986 through 2015. These costs, discounted at 3.7 percent annually, are then summed to give the discounted program cost figure reported in the text as a 1985 net present value. To calculate the cost-effectiveness measure, the emission reductions are assumed to coincide with the appropriate expenditures, that is, fuel premiums and scrubber operations. This profile of emission reductions is also discounted at 3.7 percent and summed to provide the denominator of the cost-effectiveness measure, with the discounted program cost as the numerator.

For the options examined in Chapters II and III, no resource costs or emission reductions occur between 1986 and 1990. Utilities begin to build scrubbers in 1991, and complete them in 1995 in order to meet the compliance deadline. These real capital costs are, therefore, phased in during this period, achieving the annual level predicted by the model in 1995. No variable costs (fuel premiums or scrubbing O&M) are incurred, however, until 1995, at which time all emission reductions are assumed to occur. This assumes that utilities can wait until the last possible moment to comply. During the 1995-2015 period, the emission reductions and annual costs are assumed to hold constant, with the exception of the capital costs which are phased out during the last five years.

The incentive-based options discussed in Chapters IV and V require different assumptions regarding the timing of emission reductions and the associated abatement costs. Capital costs are still phased in during the 1991-1995 period, reflecting the planning time necessary to begin scrubber installation. All variable costs, as well as emission reductions, are gradually phased in from 1987 through 1995. This embodies the assumption that utilities will switch fuels and begin to operate scrubbers earlier than assumed in the compliance date policies. While this assumption raises discounted program costs, the benefits of earlier emission reductions are reflected in the cost-effectiveness calculation. The cost and emission assumptions for the 1995 through 2015 period are the same in all chapters, although the options examined in Chapter IV might still produce tax revenues, and the Chapter V options would continue to generate revenues and require subsidies.

Why is the discount rate of 3.7 percent identical to the rate at which the trust fund accumulates interest? Choosing equal rates in this analysis means that the overall discounted program cost of an option will not depend on its period-by-period trust fund balance. This assumes that society attaches no cost to the government's holding excess trust fund balances, as long as the fund earns a rate of return sufficient to compensate contributors before their reimbursement.

Choosing a discount rate becomes especially important--and controversial--when both costs and benefits are examined. Usually the costs attributed to a public project or policy are incurred before benefits (returns) are realized, and the assumed discount rate can determine whether or not a policy represents a net economic gain for society. In this analysis, which does not estimate the dollar values of emission reduction benefits, the discount rate provides a way to compare the overall cost of policies when the timing of actual expenditures differs. The 3.7 percent annual real rate approximates the value of current consumption over the postponement implied by riskless investment--often called in economics "society's rate of pure time preference." This constitutes the lowest rate typically assumed in policy analysis; a low discount rate applied to expenditure streams raises the discounted value of program costs, but also limits somewhat the "penalty" for incurring expenditures sooner.

GLOSSARY

GLOSSARY

This glossary furnishes quick identification of the many options examined in this report. Only key provisions of each option are listed here; the reader should refer to the text for a more detailed description.

The title of each option begins with a roman numeral that indicates the chapter in which it is introduced. For the options examined in Chapters II and III, the arabic numeral designates the level of reduction mandated from 1980 emission levels (1 indicates an 8 million ton reduction; 2 indicates a 10 million ton reduction). For options described in Chapters IV, V, and VI, however, the arabic numeral has no specific meaning beyond identification.

Option II-1A: an 8 million ton rollback of SO_2 emissions that allows fuel switching; polluter pays all costs.

Option II-1B: An 8 million ton rollback of SO_2 emissions that restricts fuel switching; polluter pays all costs.

Option II-2A: A 10 million ton rollback of SO_2 emissions that allows fuel switching; polluter pays all costs.

Option II-2B: A 10 million ton rollback of SO_2 emissions that restricts fuel switching; polluter pays all costs.

Option III-1A: An 8 million ton rollback of SO_2 emissions that includes a 90 percent capital subsidy for retrofit scrubbers provided by a temporary tax on electricity generation fired by fossil fuels.

Option III-1B: An 8 million ton rollback of SO_2 emissions that includes a 90 percent capital subsidy and a 50 percent operation and maintenance (O&M) subsidy for retrofit scrubbers provided by a temporary tax on electricity generation fired by fossil fuels.

Option III-2A: A 10 million ton rollback of SO_2 emissions that includes a 90 percent capital subsidy for retrofit scrubbers provided by a temporary tax on electricity generation fired by fossil fuels.

Option III-2B: A 10 million ton rollback of SO_2 emissions that includes a 90 percent capital subsidy and a 50 percent O&M subsidy for retrofit scrubbers provided by a temporary tax on electricity generation fired by fossil fuels.

Option III-2C: A 10 million ton rollback of SO_2 emissions that requires the 50 highest emitting plants to install scrubbers, and that includes a 90 percent capital subsidy for all retrofit scrubbers provided by a temporary tax on electricity generation fired by fossil fuels.

Option VI-1: Imposes a tax on SO_2 emissions of $600 per ton, to achieve a total SO_2 rollback of 9.2 million tons.

Option VI-2: Imposes a tax on SO_2 emissions of $600 per ton, and includes a 90 percent capital subsidy for retrofit scrubbers. Achieves a total SO_2 rollback of 9.5 million tons.

Option VI-3: Imposes a tax on SO_2 emissions of $600 per ton, and includes a 90 percent capital subsidy and a 50 percent O&M subsidy for retrofit scrubbers. Achieves a total SO_2 rollback of 9.6 million tons.

Option V-1: Imposes a tax on each ton of coal sold, computed at $0.50 per pound of sulfur contained in each ton (to the extent that sulfur content exceeds 10 pounds per ton). Grants a 90 percent capital subsidy on retrofit scrubbers as well as a $0.50 per pound subsidy for any sulfur removed by a scrubber. Achieves a total SO_2 rollback of 8.9 million tons.

Option V-1: Imposes a tax on each ton of coal sold, computed at $0.50 per pound of sulfur contained per million Btus (to the extent that sulfur content exceeds 0.4 pounds per million Btus). Grants a 90 percent capital subsidy on retrofit scrubbers as well as a $0.50 per pound subsidy for any sulfur removed by a scrubber. Achieves a total SO_2 rollback of 8.9 million tons.

Option VI-1: A polluter pays rollback of SO_2 emissions based on utilities' achieving a statewide average emission rate of 1.2 pounds of SO_2 emitted per million Btus of fuel burned. Achieves a total SO_2 rollback of 9.1 million tons.

Option VI-2: A polluter pays rollback of SO_2 emissions based on utilities' achieving a plant-by-plant emission rate of 1.2 pounds of SO_2 emitted per million Btus of fuel burned. Achieves a total SO_2 rollback of 9.9 million tons.

Option VI-3: A polluter pays rollback of SO_2 emissions based on utilities' achieving a plant-by-plant emission rate of 0.7 pounds of SO_2 emitted per million Btus of fuel burned. Achieves a total SO_2 rollback of 12.3 million tons.